

National Energy  
Board



Office national  
de l'énergie

**National Energy Board  
Electricity Cost Recovery Workshop**

**Summary of Workshop Discussion**

**Delta Bow Valley Hotel, Calgary, Alberta  
9 December 2004**

**Revision One, 18 February 2005**

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**Please note: The Workshop Summary was prepared by the NEB. Participants were then asked to provide their comments on the summary. These comments are recorded, starting on page 5. Please refer to these comments when reading the document.**

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## Executive Summary

About 25 industry members and National Energy Board (NEB) representatives participated in a day-long workshop on 9 December 2004 in Calgary to explore NEB cost recovery mechanisms for the electricity industry. Concern about the cost recovery process had been expressed by some industry members in March 2004, and a review of the methodology was requested.

The industry members requesting the review believe that the current methodology is not equitable, since exporters are the only group paying NEB costs, but they are not the only beneficiaries of the NEB's programs and services. They also believe that the restructuring of the industry resulting in separation of generation, transmission, distribution and marketing functions means that it is critical for costs to be paid by the entities receiving the benefits associated with the programs and services. According to industry, a decline in export volumes in recent years, along with an increase in NEB costs associated largely with transmission line hearings, have put a further burden on the exporters.

At the workshop, the NEB gave presentations describing the current cost recovery methodology and the processes required to change the National Energy Board Cost Recovery Regulations (Cost Recovery Regulations) and to accommodate the new *User Fees Act* (UFA). The following table shows the approximate breakdown of costs.

**NEB Estimated Electricity-Related Time Breakdown  
May 2002 to September 2004**

	<b>With Sumas</b>	<b>Without Sumas*</b>
Hearings	33%	11%
Export permit applications	20%	27%
Monthly export returns	6%	8%
Market monitoring	32%	43%
Other (activities such as training, workshops, etc.)	9%	12%

\* Since the Sumas hearing was a very significant and unusual cost, NEB staff provided a breakdown of costs with Sumas removed, providing perhaps a more representative breakdown over the long term.

Industry provided some starting points for discussion about how the cost recovery process could be modified. There was general agreement that applicants should pay all the costs related to their application, whether they are exporters applying for export permits or transmission line owners applying to build an international transmission line. There was lengthy discussion about how those costs could be determined.

There was not any consensus on the recovery of other costs, such as monthly export returns or market monitoring costs. Some participants advocated for a methodology where costs could be tied to benefits. However, some industry participants said that it was not clear how they benefited from these Board activities.

The Board indicated that changes to the *National Energy Board Act* (NEB Act) are likely not possible at this time and that any changes would have to be made through the Cost Recovery Regulations.

Industry participants agreed that the Board should explore the following options.

**Options for new international transmission line applications:**

- Pay actual estimated costs for each hearing (based on number of staff hours).
- Pay flat fee for category 1, 2, 3 (category relates to the length or complexity of the hearing and would be decided at the end of the hearing with input from the company).

**Permits**

- Flat application fee for export permits.

**Non-application costs (all other costs)**

- Transmission companies to pay based on installed capacity.
- Transmission companies to pay based on the use of the transmission line (volume of exports). It could also be based on exports plus imports, or the total utilization of the line.
- NEB services (monthly export returns, market monitoring, etc) to be paid by those who benefit from them.
- Straight ratio (% for transmission companies and % for exporters).

**Next Steps**

- Draft workshop summary report sent to participants early January 2005 for comments to ensure the document accurately reflects the discussion (comment period of 14 days).
- Final workshop summary report sent to industry stakeholders for information and will be given 30 days to provide new ideas.
- Consultation on the draft cost recovery concept will take place in the spring of 2005. The concept will be distributed to the electricity industry in advance of the meeting.

A summary of the discussion during the workshop is presented in the following pages. Prepared by the NEB, this summary is not intended to be a word-for-word transcript of the proceedings, but rather the NEB's interpretation of the discussion. Participants were given the opportunity to review the summary and provided their comments. Their verbatim comments are included in a table on page 5, and should be referenced when reading the rest of the document.

The purpose of the workshop summary report is to reflect participants' comments in their own words, and the use of terminology in the report is consistent with participants' remarks. For clarification, any reference to transmission lines or owners in the report is intended to refer to transmission lines authorized by the NEB.

**NEB Electricity Cost Recovery Workshop Summary  
Comments from Participants**

<b>Page</b>	<b>Line #</b>	<b>Comment</b>	<b>Company</b>
16	10	On page 13 where it says that "New Brunswick has 14,000 megawatts of interconnection capability". This is not correct. We have 900MW of international export capability today, which will increase to 1200 after the 2nd International Power Line is completed in 2006. We have 2400MW of total interconnection capacity, which includes the current international (900) as well as inter-provincial interconnections.	NB Power Transmission Corporation
19	31	"Their only extra revenue is from export, which is a credit against load". I would clarify this by saying "Their other source of revenue is through the use of point to point transmission service, which is used by exporters or customers going through their system. This provides revenue that does not have to be provided by native load customers taking network service". The point is that there are two sources of revenues, network transmission service, which the native load pays and point to point transmission services, which exporters and those going through NB pay.	NB Power Transmission Corporation
3, 9	Table	Change Hearings to Transmission Hearings, as this more clearly reflects what the Hearings were for. Change Market Monitoring to Industry/ Market Monitoring, to avoid confusion with market monitoring functions in the Ontario and Alberta markets.	Manitoba Hydro
16	10	The statement "New Brunswick has 14,000 MW of transmission interconnection capability" is in error. The number may apply to Canada as a whole.	Manitoba Hydro
13	43	Add: pass costs to customers, <i>including export customers</i> , under their own <i>provincially approved</i> tariffs	Ontario Power Generation
13	46	Add: are difficult to forecast, since <i>large export volume changes can occur quickly as a result of either changes in supply conditions such as drought in provinces</i>	Ontario Power Generation
14	1	Add: or droughts in provinces with significant hydro capacity <i>or changes in demand in neighbouring jurisdictions due to relative pricing of alternative fuels. Due to these fluctuations, some region may pay a significant percentage of the NEB's costs one year and make little or no contribution in the next year, leaving the other exporters to make up the difference.</i>	Ontario Power Generation
14	24	Add: Costs can be passed through to <i>domestic or export</i> customers	Ontario Power Generation
15	28	Add: system, <i>if this would lead to better allocation of costs to the industry.</i>	Ontario Power Generation
16	15	Coral Energy Canada noted that if there were no wires across the border, there would be no costs. For example, Alberta has no direct	Powerex

Page	Line #	Comment	Company
		connection with the U.S. How can the NEB incorporate all the allocation nuances? Pipelines are simpler; throughput and distance are all cost based and can be easily calculated. Electricity is not that simple.	
19	22	Change the paragraph to read as follows: "Powerex indicated that putting the costs in transmission rates would be more equitable. Using the proxy of transmission capacity is not a bad idea since it can be rolled over into rates. There is more flexibility for recovery of these costs. For example, Powerex is paying over \$1 million per year as a direct cost, whereas to BCTC, with a revenue requirement of approximately \$500 million, this is the equivalent of a 0.2% rate impact."	Powerex
19	34	Powerex recalls responding to the comments by NB Power Transmission noted in that paragraph regarding the fact that some generators are sized larger than domestic market requirements and the export line allowed them to receive revenues. These situations developed in the era of vertically integrated utilities. Furthermore, the domestic retail customer benefited from the economies of scale by building a larger generator than their load would have supported at the time and that overtime the load is growing into that generating capability and reducing export capability. The export line allowed the utilities to mitigate the extra costs through export sales. In essence, even in a pure export situation as in New Brunswick, the domestic retail market benefits from exports.	Powerex
14	39	<p>At the end of Kelly Hunter’s presentation, a representative of the Transmission Council of the Canada Electricity Association stated that in addition to the graph showing decreases in the net export volume (MWh), it would have been a good idea to present the trend in earnings relating to exports for the same years for Canadian producers and marketers. It is not because export volumes go down that the marketers’ and producers’ earnings go down by the same percentage. In fact, the per MWh export sales price has gone up considerably in recent years. As a result, Canadian exporters’ revenues and earnings have probably not followed the trend in net export volumes (MWh) presented by Mr. Hunter. Furthermore, the energy storage strategy does not necessarily increase net export volumes, but it does generate revenues.</p> <p>N.B. A January 2005 Hydro-Québec press release reads:</p> <p style="padding-left: 40px;">“[TRANSLATION] While preserving the natural resource, Hydro-Québec Production has taken advantage of business opportunities on export</p>	Hydro-Québec TransÉnergie

Page	Line #	Comment	Company
		<p>markets, all to the benefit of Quebeckers, given that over the last three years alone, export markets contributed close to \$2 G to the company's earnings. The average price obtained is 10.8 ¢ per KWh. Remember, in Quebec the same kWh sells for 2.79¢."</p> <p>As a result, demonstrating that net electricity exports by Canadian producers and brokers to the United States have dropped in recent years does not necessarily mean that Canadian producers and brokers are making less money, and that as a result they should not have to pay their fair share of NEB expenses.</p>	
18	25	<p>There seems to be some confusion in the second paragraph of the chapter "Coûts mensuels liés aux exportations".</p> <p>"Hydro-Québec TransÉnergie pointed out that the monthly export statements provide no benefit to exporters and that the related costs should be included in the monitoring function. We believe that the comment was made by Hydro-Québec Production. As a result, the sentence should begin with: Hydro-Québec Production ...</p>	Hydro-Québec TransÉnergie

# 1 **NEB Presentations**

## 2 **Introduction**

3 **Valerie Katarey, Business Unit Leader, Corporate Services**

4  
5  
6 The need to review the issue of NEB cost recovery for the electricity industry was identified a  
7 year ago, when companies paying cost recovery expressed concern that the restructuring of the  
8 industry over the past number of years has resulted in inequities in who contributes to cost  
9 recovery for NEB expenses. The NEB is open to discussing these concerns and has made other  
10 cost recovery participants – members of the oil and gas industry – aware of this initiative.

11  
12 This workshop is a starting point, although thinking has already begun and some ideas have been  
13 developed. The workshop is intended to bring everyone to the same common knowledge and  
14 understanding, so that the industry and the NEB can begin to move forward.

15  
16 The regulatory regime is very complex and making changes will take some time, especially with  
17 the new UFA enacted last spring. If triggered, this initiative will likely be the first to have to  
18 comply with that Act.

19  
20 There will be a wide ranging set of views – they should all be put on the table for consideration.

21  
22 Following this workshop there will be additional opportunities to provide input.

## 23 24 25 **Overview of Services Provided by the Board**

26 **Cassandra Wilde, Applications, Economist**

27  
28 The NEB's purpose is to promote safety, environmental protection and economic efficiency in  
29 the public interest in the regulation of pipelines, energy development and trade.

30  
31 The NEB has a two-part mandate: regulatory and market monitoring functions. With respect to  
32 the electricity industry, its regulatory functions involve oversight related to the construction and  
33 operation of international power lines. Regulatory proceedings may involve oral or written  
34 hearings, and ongoing monitoring to ensure compliance. A second regulatory function involves  
35 jurisdiction over electricity exports. The NEB issues export permits and licenses, and requires  
36 exporting companies to file monthly returns.

37  
38 The market monitoring function involves reviews of all the industries regulated by the NEB –  
39 gas, oil, electricity – to acquire the necessary knowledge and understanding for the Board to  
40 make well-informed decisions in the public interest. There was a semantic distinction made, in  
41 that the Board's market monitoring is not really about monitoring 'markets' *per se*. The function  
42 is broader than that – it is perhaps closer to an industry review and may involve a number of  
43 different industry aspects, for example, reliability, trade, impacts of U.S. policies and  
44 developments.



1 Three Energy Market Assessments (EMAs) for the electricity industry have been completed in  
2 the past three years and three more are planned for release in 2005/06 on the topics of electricity  
3 markets, natural gas for power generation, and alternative and renewable power sources.  
4

5 It was noted that the Board contracted a consultant to review and obtain input on the usefulness  
6 of the market monitoring function for the three regulated industries. The report, available on the  
7 NEB web site, found that the function was viewed positively.<sup>1</sup>  
8

9 The current cost recovery process for the electricity industry worked well when the industry was  
10 primarily composed of vertically integrated utility companies. Costs were recovered based on  
11 export volumes, allowing predictable revenue for the Board and predictable expenses for the  
12 industry.  
13

14 However, the industry has undergone significant change, starting with the restructuring initiated  
15 with FERC Order 888. Now export permits tend to go to smaller entities such as generators or  
16 marketers. Exports have also decreased in recent years, to a large degree because of lower water  
17 levels.  
18

19 NEB costs associated with electricity have also risen from \$1.8 million in 2001 to \$5.2 million in  
20 2004, reflecting an increased number of permit applications -- many resulting from the IMO  
21 market opening in Ontario -- international power line applications, higher overall Board costs,  
22 and an increased portion of time spent on electricity matters. NEB hours spent on electricity  
23 matters are decreasing this year, but it may be a while before the impact of reduced hours is seen  
24 in electricity billing due to the three-year cost recovery cycle.  
25

26 **NEB Estimated Electricity-Related Time Breakdown**  
27 **May 2002 to September 2004**  
28

	<b>With Sumas</b>	<b>Without Sumas*</b>
Hearings	33%	11%
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Other (activities such as training, workshops, etc.)	9%	12%

29 \* Since the Sumas hearing was a very significant and unusual cost, NEB staff provided a breakdown of costs  
30 with Sumas removed, providing perhaps a more representative breakdown over the long term.

<sup>1</sup> [http://www.neb-one.gc.ca/publications/internalauditreports/2003/evaluationenergymarketssupplymonitoring\\_2003\\_09\\_e.pdf](http://www.neb-one.gc.ca/publications/internalauditreports/2003/evaluationenergymarketssupplymonitoring_2003_09_e.pdf)

1 **Current Cost Recovery Methodology**

2 **Dan Philips, Corporate Service, Team Leader, Finance**

3  
 4 Under the Cost Recovery Regulations, companies are invoiced for recoverable costs, of which  
 5 approximately 75 percent are salaries, with the remainder operating and maintenance costs. The  
 6 Auditor General conducts an annual audit of recoverable NEB costs and the pool of costs is  
 7 certified. Not all costs are recoverable, such as the costs of activities relating to frontier areas,  
 8 work for other agencies, or overhead related to non-recoverable costs.

9  
 10 Companies pay their share of recoverable costs in three ways:

- 11 ▪ Greenfield levies (pipeline– new companies only)
- 12 ▪ Fixed fees (small and intermediate companies and other commodities)
- 13 ▪ Sharing remaining pool of costs (large companies)

14  
 15 Small and intermediate companies have clear and straightforward obligations, while the  
 16 provisions for large companies are more complex.

17  
 18 **NEB Cost Recovery Breakdown**

Size	Small Companies	Intermediate Companies	Large Companies
Pipelines	Cost of service = < \$1 million	Cost of service between \$1 million and \$10 million	Cost of service = > \$10 million
Electricity Exporters	< 50,000 MWh in 12 consecutive months	Authorized to export between 50,000 and 250,000 MWh in 12 consecutive months	Authorized to export =>250,000 MWh in 12 consecutive months
Fees	Administration fee of \$500	Administration fee of \$10,000	Fees based on detailed formulas (except for large commodity pipelines that pay a fixed fee of \$50,000.00)

19  
 20 The share that large companies must pay is determined by the time the NEB spends on each  
 21 commodity as well as the individual and aggregate activity levels of the companies in each  
 22 commodity group. The billing process is designed to ensure that current NEB activities are  
 23 funded from current billings. This is accomplished in a three-year cycle, as follows.

24  
 25 **Three-Year Cost Recovery Process for Large Companies**

Year One	Year Two	Year Three
Companies pay share of estimated costs (Year One)	Companies pay share of estimated recoverable costs for current year. (Year Two)	Companies pay share of estimated recoverable costs for Year Three – adjusted for differences between Year One estimates and actual as determined in Year Two.
NEB collects relevant company information	Actual Year One costs are audited	NEB collects relevant company information
NEB estimates costs for Year Two and amount each company will be invoiced	Differences between Year One estimates and actual are calculated	
NEB advises companies on their Year Two billings	NEB collects relevant company information and issues invoices for Year Two	

1 It was noted that the NEB's allocation process involves two calculations. The first one is based  
2 on the amount of staff time spent on each commodity. The second relates to non-specific time,  
3 which is time that cannot be attributed to a specific commodity, such as staff annual leave and  
4 training not specific to a commodity. Non-specific time is allocated across all commodities  
5 proportionately, based on the first allocation. Close to half of staff's time falls into this non-  
6 specific category.

7  
8 There was discussion about the appropriateness of the charges under this allocation system and  
9 whether the electricity industry is being penalized financially compared to the gas industry, since  
10 pipeline hearings often involve significant travel, while electricity applications usually only  
11 require a written process. However, there were four electricity hearings in the past four years –  
12 with Sumas being the most significant one. It was noted that, in any case, the Board's travel  
13 budget is quite small – only about five percent – and would not create a significant impact.

14  
15 The Board also indicated that large oil or gas pipelines costs may be capped at two percent of the  
16 company's cost of service, but the company must apply for this relief. Because of fluctuations in  
17 export activity, costs allocated to large electricity exporters are based on a four-year rolling  
18 average of actual exports.

19  
20 It was also noted that there has been an increase in electricity costs as a percentage of total NEB  
21 costs -- from 3.7 percent in 1998 to 13.9 percent in 2005. The increase is largely due to the  
22 number of hearings for international transmission lines since 2001. From 1998 to 2000, there  
23 were no hearings at all, so the jump in costs was significant.

24  
25 Industry participants asked questions about the allocation process, and how contractors or  
26 consultants are treated. The NEB indicated that consultants are not hired very often, but they are  
27 part of the operations and maintenance costs that are allocated across commodities based on the  
28 percentage of time spent on each commodity.

29  
30 One industry participant noted that whichever industry is busy seems to take on the largest share  
31 of expenses. If none of the commodities are busy, then there is *pro rata* sharing.

32  
33 Another industry participant wondered if there is a business plan to determine where the NEB  
34 will be focusing its activities. While a three-year business plan is posted on the NEB web site,  
35 Board representatives noted that much of their work is unpredictable and based on what industry  
36 is doing. If there are no current applications, then they look at long-term projects, such as  
37 reinvestment in infrastructure, additional research or internal systems. The first priority is always  
38 to deal with external demand from industry. On the other hand, when the workload is very  
39 heavy, for example with the Mackenzie Gas Pipeline project, additional resources are added.

40  
41 It was noted that the NEB's electricity team operates with an annual budget of less than  
42 \$1 million for all staff, travel, contracts, etc. Team members do not necessarily devote all their  
43 time to electricity matters.

1 **The Process for Drafting and Amending Regulations**  
2 **Chantal Briand, Operations, Regulatory Analyst**

3  
4 There are a number of legal considerations when drafting or amending NEB related regulations,  
5 including various acts, regulations, international agreements, and policies.  
6

7 The regulation development process involves six phases:

- 8 1. Conception and development
  - 9 2. Drafting regulations
  - 10 3. Examination by Justice and for approval by Treasury Board
  - 11 4. Pre-publication in the *Canada Gazette*, Part 1, with Comment Period
  - 12 5. Final submission to Justice, Privy Council Office and Treasury Board
  - 13 6. Promulgation (*Canada Gazette*, Part II)
- 14

15 There is consultation during the first four phases of the process that can take a variety of forms.  
16 By the time the draft regulation reaches Phase 4, there should be no surprises.  
17

18 There was some discussion on whether the contemplated amendments would trigger the new  
19 UFA promulgated in March 2004. The UFA provides for Parliamentary scrutiny and approval of  
20 user fees set by regulating authorities and may have an impact on the regulation development  
21 process for this project. The applicability of the UFA will depend on the nature of the  
22 amendments adopted. If it is triggered, additional consultation will be required, including  
23 notifying potential payees about the proposal, seeking input on how services could be improved,  
24 conducting an impact assessment, establishing an independent advisory panel to address any  
25 complaints, conducting a comparison with the fees of other countries, and tabling the proposal in  
26 Parliament.  
27

28 The consultation process will be critical to identify concerns, disclose information and to allow  
29 stakeholders the opportunity to provide input. The process may be delayed if the proposed  
30 amendments are complex or controversial. The process can take 18-24 months or longer.  
31

32 Valerie Katarey noted that the NEB is an agency of the federal government, with up to nine  
33 Board members who meet weekly to make decisions. Independent Board members are appointed  
34 by Parliament. They report through the Minister but are not accountable to the Minister. NEB  
35 staff support the Board members.

## 1 **Industry Presentations**

### 2 **Canadian Electricity Association**

#### 3 **Dan Goldberger, Senior Advisor, Power Marketer's Council**

4  
5  
6 The Canadian Electricity Association (CEA) was one of two industry stakeholders who gave a  
7 presentation at the workshop.

8  
9 The CEA is composed of about 30 corporate utility members, representing almost 95 percent of  
10 all installed generating capacity, transmission, distribution, customer and power marketing in  
11 Canada. The CEA's governance structure reflects the business lines: Generation Council,  
12 Transmission Council, Distribution Council, Customer Council and Power Marketer's Council.

13  
14 The NEB's Cost Recovery Liaison Committee meets three times a year with the sector. Mike  
15 MacDougall of Powerex is the CEA representative on the committee, representing marketers'  
16 interests. Tim Egan is also involved. The committee is an advisory committee to the Board and  
17 not a decision-making body. Additional members from the electricity sector are welcome.

18  
19 The Transmission and Power Marketer's Councils, which have been following the cost recovery  
20 issue closely, agree that applicants should pay the directly related costs for processing  
21 applications for constructing and operating international power lines and electricity exports.  
22 However, no agreement could be reached on how to divide the remaining NEB costs (such as  
23 studies, staff, office space, equipment and travel).

24  
25 CEA also noted emerging concerns, such as rising NEB costs and the issue of non-paying  
26 entities creating costs for others (Sumas). It was suggested that the NEB develop a new policy to  
27 recapture such costs, for example, an application fee.

### 28 **Manitoba Hydro**

#### 29 **Kelly Hunter, Market Access Officer, Manitoba Hydro**

30  
31  
32 Manitoba Hydro noted that there needs to be a more equitable approach for NEB cost recovery –  
33 costs should be paid by those who derive the benefits. Under the current methodology, exporters  
34 pay the whole cost, but they are not the only ones deriving benefit. There are reliability and  
35 economic benefits for transmission lines and customers. These benefits need to be recognized in  
36 the methodology.

37  
38 The Sumas Project was raised as an example of an import-only transmission line for which  
39 exporters paid millions for hearing costs yet stand to receive no benefit. Further, no benefit  
40 would have been received even if the project had been approved. Manitoba Hydro suggested that  
41 it would be more appropriate to allocate costs to international transmission line owners to capture  
42 import, export and reliability benefits. Furthermore, transmission line owners can pass costs to  
43 customers under their own tariffs.

44  
45 The current decline in exports along with growing deregulation need to be reflected in the new  
46 cost recovery methodology. Furthermore, electricity exports are difficult to forecast, since

1 droughts in provinces with significant hydro capacity can cause large export volume swings. The  
2 regions not in drought pick up the cost for those experiencing drought. The four-year rolling  
3 average process is very complex and export volumes cannot be predicted very well.

4  
5 Export volumes are not suitable to set and allocate costs, for the following reasons:

- 6 ■ Transmission line flows are bi-directional and flow direction can change at any time.
- 7 ■ Economic and reliability benefits of lower priced imports are not recognized in the current  
8 methodology (substantial imports recently in Ontario and Manitoba – Québec may be facing  
9 a shortfall).
- 10 ■ Reliability benefits are not captured – they occur without export flow. There can be  
11 extremely high reliability value for very minimal flows under emergency conditions.
- 12 ■ Generators also receive reliability benefits from connecting to a very strong grid.

13  
14 Manitoba Hydro supports the CEA position that applicants should pay directly related costs of  
15 their applications. As well, the company would support a greenfield fee for new international  
16 transmission lines like that for natural gas pipelines. All other costs should be allocated to  
17 owners of transmission lines on the basis of their share of total installed international  
18 transmission capacity. Pipelines do not pay a fee based on their export volumes. Manitoba Hydro  
19 expressed interest in moving to a process that may be more standardized with pipelines.

20  
21 Basing the allocation on installed capacity rather than export volumes has a number of benefits:

- 22 ■ Stable number – not affected by droughts – that will grow over time.
- 23 ■ Captures the full value of the interconnections, e.g., exports, imports and reliability.
- 24 ■ Costs can be passed through to customers, marketers, taxpayers under provincial regulatory  
25 processes.
- 26 ■ Simple to administer.

27  
28 Manitoba Hydro noted that in previous years it did not matter whether it was the transmission  
29 owner or exporter who was charged – it was all part of the same company. Now each function  
30 has a separate company or business unit. New parties have entered the market. Exporters and  
31 transmission owners are different entities.

32  
33 Other industry participants also questioned whether exporters should pay all NEB costs in the  
34 face of declining export activity. Since 1996, electricity imports have increased. It may be that  
35 Canada's 'glory days' of exporting electricity are over.

36  
37 Manitoba Hydro added that while there has been an increase in the number of export  
38 applications, there has been no increase in export volumes. However, processing these permits is  
39 not an overly time-consuming activity, according to the NEB.

## 1 **Workshop Discussion**

### 3 **Application Fees & Other Cost Allocation Methodologies**

5 Hydro-Québec TransÉnergie agreed with Manitoba Hydro that the applicant should pay for their  
6 own expenses, but could not agree to base any allocation component of cost recovery on installed  
7 international transmission capacity. The company stated that transmission providers should not  
8 be the only ones to assume those costs. Both public and private interests must be taken into  
9 consideration, and provincial regulators will ultimately have to decide if the costs will be  
10 included in rate base. Where is the public interest when new exporters sell power to the U.S.?  
11 Why should consumers have to pay for that?

13 Manitoba Hydro noted that even if only one measure was implemented – to have the applicant  
14 pay for its own costs – that would be a great accomplishment. Then the other allocated costs  
15 would decrease substantially.

17 NB Power Transmission noted that costs incurred by provincial regulators related to a specific  
18 hearing, e.g., board time and facilities, are assigned to the applicant through a two-year process.  
19 If the application is not approved, the proponent still runs the risk of incurring those costs. This  
20 model could be used for the NEB.

22 However, the NEB noted that it currently does not have any tools to track direct costs for  
23 individual projects. It can track staff hours, but not the costs associated with those hours. The  
24 per hour salary costs of various staff are not calculated by the present system and such a system  
25 would be costly to implement. The Board asked industry if they would be willing to pay the cost  
26 of creating and managing a new tracking system. There was a lengthy discussion about the  
27 tracking process. Some industry participants believed that the NEB should have a better tracking  
28 system.

30 Others thought that perhaps the costs could be averaged, based on the recorded hours, or a proxy  
31 cost developed.

33 Manitoba Hydro also suggested that industry monitoring costs should be shared among all  
34 players, since some of these costs do not specifically relate to exports. Hydro-Québec  
35 TransÉnergie agreed that grid studies should be funded by transmission owners and market  
36 studies funded by marketers. There could be three classes of fees:

- 38 1. Application fees.
- 39 2. Special reports, e.g., targeted at transmission, generation or marketing, should be paid for  
40 by the sector.
- 41 3. Overhead costs, including maintenance, etc., should be allocated somehow.

43 Powerex noted that it is not necessarily the same entity exporting as importing. The NEB only  
44 regulates exports, not imports. Since transmission facilities are bi-directional, everyone benefits  
45 and everyone should contribute. The best way to accomplish that is through transmission tariffs.

1 If the NEB, a federal regulator, goes through a process to determine a fair allocation – then  
2 provincial regulators should find those costs acceptable.

3  
4 Hydro-Québec TransÉnergie noted that if the costs are included in the tariffs, then Canadian  
5 customers would be paying for everything, including export related costs. Ontario Power  
6 Generation suggested that this concern could be addressed through tariff design. If the NEB  
7 determines a certain cost allocation, it is hard to believe that the provincial authority would over-  
8 rule that, noted Manitoba Hydro.

9  
10 NB Power Transmission noted that it is possible for the process to backfire. New Brunswick has  
11 14,000 megawatts of interconnection capability.\* If export volumes are down, then revenues are  
12 also down – and costs revert back to customers in those areas. Powerex noted that those  
13 customers get other benefits, such as improved reliability.

14  
15 Coral Energy Canada noted that if there were no wires across the border, there would be no  
16 costs. For example, Alberta has no direct connection with the U.S. How can the NEB incorporate  
17 all the allocation nuances? Pipelines are simpler; throughput and distance are all cost based and  
18 can be easily calculated. Electricity is not that simple.

19  
20 Hydro-Québec TransÉnergie noted a concern about public opinion – if there is an increase in  
21 their electric rates, the public will ask why. They will make the link and question why they are  
22 paying for export-related costs. Coral Energy commented that if there was a line strictly for  
23 export, it would be difficult to share costs with others.

24  
25 Regarding the greenfield levy applicable to oil and gas pipelines, it was clarified that these costs  
26 are paid only once – the first time a proponent proposes a facility and receives approval. Other  
27 facilities by the same proponent, even if greenfield, would not be subject to this levy. If the  
28 facility does not receive approval, then the rest of the industry picks up the costs. The situation  
29 with Sumas was similar – others are paying Sumas costs. This is the case because the Board is  
30 authorized to only charge cost recovery to companies “authorized” to construct or operate a  
31 pipeline or international transmission line, or export electricity.

32  
33 Some concern was expressed about frivolous applications. Powerex suggested a two-step process  
34 where the company could be tested under the NEB Act before it applies. Coral Energy noted that  
35 gas pipeline companies must expend a huge amount of money before they get to the application  
36 stage.

37  
38 BC Transmission noted that the NEB appears reticent to change the NEB Act. The NEB noted  
39 that the timeline to change the Act would be at least five years. It is always difficult to get  
40 amendments on the government agenda, and particularly so in the context of a minority  
41 government. Changes to the NEB Act to accommodate cost recovery changes would not likely  
42 be a government priority at this time.

43  
44 NB Power Transmission suggested perhaps having a 4-5 year average to reduce the cost spikes  
45 caused by four hearings over the past three years. The Board noted that it does not make sense to  
46 go too far back in time, since the industry structure has changed dramatically.



1 With the difficulty in tracking costs associated with each application, it was suggested that  
2 export applications were fairly routine and perhaps could have a flat fee associated with them,  
3 therefore alleviating some of the difficulty in tracking time and costs.

4  
5 It was also suggested that transmission line applicants could also be billed on a flat fee basis.  
6 Others argued that that would be difficult, since hearings tend to be more unique and that a proxy  
7 should be developed to identify actual costs.

8  
9 The NEB noted that there can be significant variation in the amount of time and effort for each  
10 hearing – with a number of variables such as the number of interveners, whether the lines are  
11 near population centres or require comprehensive study reports under the Canadian  
12 Environmental Assessment Act.

13  
14 Manitoba Hydro suggested that another way would be to allocate so many dollars per kV. This  
15 process assumes that the higher the voltage, the greater the amount of work. However, there are  
16 other factors influencing cost, such as length of the line and its location.

17  
18 Powerex noted the differences between pipelines and transmission lines. Generally, pipelines are  
19 long and big, but international transmission lines are often short interconnections at the border.  
20 The location is critical – it makes a big difference when the project is located near densely  
21 populated Abbotsford, compared to Manitoba.

22  
23 BC Transmission suggested that there could be flat fees based on three or five levels of  
24 complexity or magnitude related to transmission line projects, just as there are three categories of  
25 companies: small, intermediate and large.

26  
27 It was suggested that the NEB could determine the level of cost once interveners have registered.  
28 If there are many interveners, it could be considered a category three; no interveners would be a  
29 category one. The applicant could indicate the anticipated category and the Board could decide  
30 once the process was underway or at the end of the hearing. The NEB noted the difficulties  
31 associated with determining the category of a hearing at the beginning of the process.

32  
33 Another method to determine hearing costs could be to set a fee for each day of hearing time.  
34 While hearings can vary in length, the Board indicated that pre-hearing work is required for all  
35 hearings and that the length of hearing is not always indicative of the amount of work done by  
36 the NEB in advance of the hearing. In addition, it is difficult to predict how long a hearing will  
37 take. Sometimes interveners do not show up at all and hearings scheduled for a week can take  
38 only one day, but the Board will have spent the pre-hearing resources for the anticipated one-  
39 week hearing.

40  
41 NB Power Transmission believed that the number of days of hearing was directly related to the  
42 amount of pre-work that was done by the applicant. If the pre-work is done well and responses to  
43 Information Requests are handled properly, then the hearing will be shorter. If the applicant  
44 works hard to reduce the length of the hearing this way, the company should receive some credit  
45 for that effort. Others noted that this effort would be recognized if the costs are ‘trued up’ at the  
46 end of the process.

1 There was discussion about whether the costs should be true or proxy. Powerex indicated that  
2 there would be no point in doing an upfront estimate, if a ‘true up’ will take place at the end. It  
3 was suggested that the existing three-year rolling system could be used to finalize applicant  
4 costs. However, it was noted that with a major event such as a Sumas-type hearing, initial over-  
5 funding might occur if billing took place quarterly for estimated actual costs. Costs could also be  
6 billed at the end of the hearing.

7  
8 The Board reiterated that with the current system, it would not be possible to do a ‘true up’ since  
9 staff time cannot be broken down into actual costs. BC Transmission suggested that an average  
10 cost per staff person be developed as an input into the proxy.

11  
12 Hydro-Québec TransÉnergie indicated that there might be some possibility of creating a shortfall  
13 – if a category one application turns out to be a more expensive category three, then extra costs  
14 would be shared with others. However, that can be rectified at the end of the hearing.

### 15 16 17 **Monthly Export Costs**

18  
19 It was not clear to participants who benefits from monthly export returns. These are regulated  
20 monthly reports required from exporters. The NEB takes these reports and creates a database that  
21 is used for a variety of purposes. The annual cost for this is in the order of \$80,000. There was an  
22 ensuing discussion on whether the data is really needed. The NEB noted that the filing of returns  
23 is required by the *National Energy Board Export and Import Reporting Regulations*.

24  
25 Hydro-Québec TransÉnergie noted that monthly export returns provide no benefit to exporters.  
26 They should be included in monitoring. NB Power Transmission indicated that this category is a  
27 burden that someone has to pay. Should it be exporters?

28  
29 Hydro-Québec TransÉnergie wondered if there was any similar data collection for transmission.  
30 The NEB noted that there is no requirement in the Regulation to collect data on transmission,  
31 except for MWh, and no legislation for collecting returns with transmission data.

### 32 33 34 **Industry or Market Monitoring Costs**

35  
36 Monitoring costs are a significant component of cost recovery – over 30 percent. There was a  
37 discussion on whether some of these costs should be allocated to transmission companies. The  
38 Board was asked what benefits accrue to industry as a result of monitoring activities. The Board  
39 noted that the primary intent of the monitoring is for the Board to maintain expert knowledge  
40 about the industry. Electricity staff at the NEB constitutes a small and concentrated group –  
41 monitoring helps build their expertise.

42  
43 Some industry participants agreed that international transmission line owners could pay a portion  
44 of these costs but wanted the portion to reflect the benefit received. Hydro-Québec TransÉnergie  
45 noted that if there is a link demonstrating the importance of this information for transmission line

1 owners, then perhaps there is something to negotiate. Powerex noted that transmission line  
2 owners are a better proxy than exporters for the purposes of the information being gathered.

3  
4 Ontario Power Generation noted that the participants had agreed that there are some costs that  
5 should be shared – appropriately. Exporters should not bear the total burden. Just because there  
6 are no specific benefits for transmission owners, does not mean that they should not be paying a  
7 portion.

8  
9 Hydro-Québec TransÉnergie suggested that if a transmission line benefits, e.g., if it has been  
10 used to store and sell power at a better price, then perhaps it should pay a portion. This benefit –  
11 and the percentage -- may change from year to year. Others noted that this type of allocation may  
12 be difficult to implement – since some lines are export only, others are both import and export.

13  
14 NB Power Transmission noted that its interconnection with Maine serves Prince Edward Island  
15 and Nova Scotia from a reliability perspective, so it would be difficult to allocate monitoring  
16 costs based on local load to reflect received benefits. With multi-jurisdictions, it is very difficult.

17  
18 One suggestion was to allocate monitoring costs across Canada on an installed capacity basis –  
19 and have each transmission line owner design tariffs to incorporate those costs. This  
20 methodology might be the best way to flow those costs through to the ultimate end beneficiary.

21  
22 Powerex indicated that the NEB allocation is already present in retail rates as part of generation  
23 costs. Putting the costs in transmission rates would be more equitable. Using the proxy of  
24 transmission capacity is not a bad idea since it can be rolled over into rates. There is more  
25 flexibility for recovery of these costs. Powerex is paying over \$1 million – without any regulated  
26 rate base to recover those costs.

27  
28 A further step might be to look at the use of the transmission line for how costs could be  
29 allocated. There was discussion on how that might be implemented. Using a deferral account,  
30 exporters could receive allocated charges that they pass on to next year's customers. NB Power  
31 Transmission noted that their local load pays based on noncoincident peak. Their only extra  
32 revenue is from export, which is a credit against load.

33  
34 Hydro-Québec TransÉnergie wondered if the point-to-point tariff could be increased and not the  
35 load tariff. The local load should not be paying for export. But the local load benefits just from  
36 having the line in place. Some of the lines have been built to take advantage of economies of  
37 scale associated with generation. In the case of New Brunswick, two large generation projects  
38 were being planned, but the province could not use the entire capacity right away. James Bay in  
39 Québec was similar. There was discussion about the degree to which any of the international  
40 lines were built to meet reliability needs. Those were the drivers for interconnection. Ultimately  
41 the benefits from international lines need to be more fully articulated, including reliability,  
42 wheel-through, reserve-sharing, etc.

43  
44 NB Power Transmission suggested that since the Minister receives monitoring information, then  
45 the federal government should also provide some funding. The work serves the public interest.  
46 Manitoba Hydro agreed that there may be federal interest in industry monitoring, but a cost

1 allocation mechanism is needed that allocates Canadian/federal interest across a broader base of  
2 Canadians -- not just exporters. The NEB noted that it was not within its mandate to make that  
3 kind of decision.

4  
5 NB Power Transmission noted that if there is to be true cost allocation, then the information  
6 could or should be sold, although it was not a practical option for the short-term.

7  
8 The workshop ended on that note as all the participants agreed that the key elements had been  
9 discussed in sufficient detail for the time being and the NEB noted that additional opportunities  
10 to provide comments would be available throughout the consultation process.

11

## 12 **Next Steps**

13

14 The Project Manager indicated that input is both welcome and needed. The industry participants  
15 agreed with the consultation process that was proposed:

16

- 17 ■ Draft workshop summary report sent to participants early January 2005 for comments to  
18 ensure the document accurately reflects the discussion (comment period of 14 days)
- 19 ■ Final workshop summary report sent to industry stakeholders for information and will be  
20 given 30 days to provide new ideas.
- 21 ■ Consultation on the draft cost recovery concept will take place in the spring of 2005. The  
22 concept will be distributed to the electricity industry in advance of the meeting.

## Appendix A. Options and Issues Discussed at the Workshop

Industry provided some starting points for discussion about how the cost recovery process could be modified. The highlights are summarized as follows.

### Application Costs

Applicant Pay -- General Agreement by Industry Participants:

- All industry participants agreed that applicants should pay all the costs related to their application, whether they are exporters applying for export permits or transmission line owners applying to build an international transmission line.

Applicant Pay -- Issues to be Addressed:

- Is it possible to require applicants to pay costs associated with their application if their application is not approved or must those costs be shared among all?
- What risk, if any, is there that the provincial regulator will not approve the NEB costs paid by the applicant? What can or should be done to alleviate that risk?
- Are frivolous applications a concern? Are there sufficient checks and balances in place to deal with frivolous applications?
- How should the costs be determined? (there is no staff-related cost tracking mechanism at the NEB).
- Should a cost tracking mechanism be developed? If so, how will its development be funded?
- A flat fee was suggested as an alternative to tracking actual costs.
- Charging a flat fee for export applications would be relatively simple. They are more routine than transmission line applications, which can vary substantially in length and cost.
- For transmission line applications, perhaps three different levels of project complexity or magnitude could be applied, with a set of flat fees associated with each category.
- Should there be a cap on the amount that an applicant must pay?
- When should the applicant be billed – e.g., quarterly or at the end of the hearing?
- To what degree should the fees reflect the actual costs? Should there be a ‘true up’ after the hearing to reflect actual costs?

### NEB Costs Associated With:

Monthly Export Returns

- Monthly export returns must be filed by exporters, according to the NEB Act and the *National Energy Board Export and Import Reporting Regulations*.
- Industry participants were not sure they received any benefit from the work associated with these returns.
- Some industry participants suggested that these costs be categorized under monitoring, while others thought they related to export applications.

Industry or Market Monitoring

- Should international transmission line owners be asked to pay a portion of these costs?
- What portion should the transmission line owners pay?

- How should the costs be allocated? Should they be allocated based on who receives the benefit from the activities? On installed capacity? On straight ratio?

### **Other Issues**

Changes to the NEB Act are likely not possible at this time and any changes will have to be made through the Cost Recovery Regulations.

## Appendix B. Workshop Attendees' List

Company	Attendee	Position
TransAlta Energy Marketing Corp	Cathy Manuel	Senior Business Analyst
Canadian Electricity Association	Dan Goldberger	Senior Advisor Financial & Taxation Issues
IMO	Amir Shalaby	Manager, Regulatory Affairs
NB Power Transmission Corporation	Wayne Snowdon	VP Transmission
Ontario Power Generation	Barry Green	Director, Markets & Research
Hydro-Québec TransÉnergie	Yves Dallaire	Manager, Business Development
SaskPower	Shannon Rayner	Senior Regulatory Advisor
Manitoba Hydro	Kelly Hunter	Market Access Officer
Powerex Corp.	Mike MacDougall	Manager, Trade Policy
BC Transmission Corporation	Denise Mullen-Dalmer	
Hydro-Québec (HQP & MEHQ)	Erik Bellavance	Senior Advisor
Alberta Department of Energy	Katherine Braun	Director, Electricity Policy
NorthPoint Energy	Pat Hall	CFO
Canadian Electricity Association	Timothy Egan	Senior Policy Advisor
Coral Energy Canada Inc.	Tomasz Lange	Manager Transportation
National Energy Board	Chantal Robert	Project Manager
National Energy Board	Chantal Briand	Assistant Project Manager
National Energy Board	Claire McKinnon	Senior Counsel
National Energy Board	Lauren Bell	Counsel

**Please note: The Workshop Summary was prepared by the NEB. Participants were then asked to provide their comments on the summary. These comments are recorded, starting on page 5. Please refer to these comments when reading the document.**

<b>Company</b>	<b>Attendee</b>	<b>Position</b>
National Energy Board	Valerie Katarey	Business Unit Leader, Corporate Services
National Energy Board	Dan Philips	Team Leader, Finance
National Energy Board	Cassandra Wilde	Economist
National Energy Board	Karla Reesor	Facilitator
National Energy Board	Kym Hopper-Smith	Logistics Coordinator
National Energy Board	Julian Emanuel	Team Leader, Electricity Team
National Energy Board	John McCarthy	Business Unit Leader, Commodities
Sari Shernofsky Corporate Communication	Sari Shernofsky	Consultant